THE PSDF--A KEY STEP TOWARDS COMMERCIAL READINESS FOR COAL POWER – AN UPDATE

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I. SUMMARY

The Power Systems Development Facility (PSDF) near Wilsonville, Alabama, is a joint project of the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), Southern Company, and other industrial participants currently including the Electric Power Research Institute (EPRI), Siemens Westinghouse Power Corporation, Kellogg Brown & Root (KBR), and Peabody Energy. The PSDF is an engineering scale demonstration of key components of advanced coal-fired power systems designed at sufficient size to provide data for commercial scale-up.

Operation of the KBR transport reactor at the PSDF, in combination with a high-temperature, high-pressure filter, has shown that it offers many advantages over current gasifiers and combustors that can lead to successful commercialization. These include high carbon conversion with a variety of fuels, high sulfur capture, a small footprint with a high thermal throughput, and a simple and robust mechanical design.

Southern Company has developed a conceptual commercial plant design and cost estimate for an air-blown Transport Reactor Integrated Gasification (TRIG™) combined cycle (TRIGCC™) power plant based on a General Electric (GE) 7FA combustion turbine. This paper is an update of information presented at the DOE Clean Coal and Power Conference in Washington, D. C. on November 19-20, 2001. Since this paper was originally presented significant improvements have been made in the projected environmental performance of the process. These environmental improvements will add approximately $50/kW to the capital cost and slightly decrease the cycle performance. However, other changes will improve the net efficiency. Since the cost estimate and performance calculations are currently being totally revised, these changes are not included below.

The TRIG™ design produces 298.4 MW, net, with a lower heating value (LHV) heat rate of 7,830 Btu/kW-hr (43.6 % efficiency) at average annual ambient conditions. Originally

projected SO_2 emissions were 0.10 lb/MMBtu and NO_X emissions were 0.07 lb/MMBtu. Current projections are 0.02 lb/MMBtu for SO_2 emissions and 0.04 lb/MMBtu for NOx emissions. The estimated total plant cost for this Serial No. 1, greenfield plant is $1,290/kW (excluding the cost of capital during construction and startup costs).

This one-on-one TRIG™ configuration for a nominal 300 MW facility does not take advantage of potential economies of scale, but rather minimizes the initial investment for a first-of-a-kind facility. The total plant cost for a 600 MW Serial No. 2 plant is projected to be $1,040/kW and the LHV heat rate is projected to be 7,420 Btu/kW-hr (46.0% efficiency).

II. INTRODUCTION

The Power Systems Development Facility (PSDF) near Wilsonville, Alabama, is an engineering scale demonstration of several key components of advanced coal-fired power systems (PSDF web site: "http://psdf.southernco.com/"). The PSDF was designed at a size sufficient to test advanced power systems and components in an integrated fashion and provide data for commercial scale-up.

The PSDF is a joint project of the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), Southern Company, and other industrial participants currently including the Electric Power Research Institute (EPRI), Siemens Westinghouse Power Corporation, Kellogg Brown & Root (KBR), and Peabody Energy. Southern Company is a super-regional energy company with more than 32,000 megawatts of electric generating capacity in the Southeast, and is one of the largest users of coal in the United States, generating more than 23,000 megawatts from this low-cost domestic fuel source.

Process Systems at the PSDF

A primary purpose of the PSDF is to test particulate control devices (PCDs) for advanced coal-based power systems. Tests are currently being performed on a variety of ceramic and metal candle filter elements housed in a Siemens Westinghouse filter vessel. Filters have been exposed to particulate-laden gases from both combustion and gasification at temperatures from 700 to 1,400°F.

Two separate trains were constructed at the PSDF to supply gas to the PCDs: a KBR transport reactor and a Foster Wheeler Advanced Hybrid Pressurized Fluidized Bed Combustion system. These technologies were selected for their flexibility in supplying gases to the PCDs and for their potential to be developed into cost-competitive, environmentally acceptable coal-based power plants. The Foster Wheeler combustor was operated for 170 hours on coal in 2000. Because Foster Wheeler has redefined its advanced coal commercial offering, further tests of the Foster Wheeler systems at the PSDF have been cancelled.

Tests of the KBR transport reactor as a combustor have been completed. Tests of the transport reactor as an air-blown gasifier are under way, and show promise for commercial applications. Initial tests as an oxygen-blown transport gasifier are planned during 2002. This paper will review tests of the transport reactor and its associated PCD and present a study of a commercial design of an air-blown transport gasifier-based power plant.

The transport reactor operates at considerably higher circulation rates, velocities and riser densities than conventional circulating beds, resulting in higher throughput, better mixing, and higher mass and heat transfer rates. Because of its operating conditions, the transport reactor is well-suited to high ash, high melting point coals. Synthesis gas from a transport reactor in gasification mode can be used to fuel a combustion gas turbine or a fuel cell.

A schematic of the transport gasifier is shown in Figure 1. Fuel, sorbent, steam, and air are combined in the mixing zone with solids recirculated from the standpipe. The gas with entrained solids moves up the mixing zone into the riser (which has a slightly smaller diameter) and enters the disengager. The larger particles in the syngas are removed by gravity separation in the disengager and most of the remaining particles are removed in the cyclone. The syngas stream exits the cyclone to a gas cooler and then goes to a PCD for final particulate removal. The solids collected by the disengager and cyclone are recycled to the mixing zone through the standpipe and J-leg. When configured as a combustor, the transport reactor also includes a fluidized-bed solids cooler (not shown in Figure 1) that removes heat from the circulating solids before they are returned to the mixing zone.

III. OPERATION AND RESULTS

Combustion Tests

The transport reactor ran in combustion mode for approximately 5,000 hours from 1996 through 1999 at typical operating conditions of 1,625°F and 215 psia. Fuels used included bituminous coals from Alabama, East Kentucky and Illinois, a mixture of three sub-bituminous coals from the Powder River Basin (PRB) in Wyoming, and petroleum coke from an Alabama refinery. Stable operations were demonstrated for all fuels and sorbents.

More than twenty types of filter elements were tested in the PCD during combustion, including monolithic oxide, monolithic SiC, composite, and metal materials. The longest exposure time for individual filters was about 3,300 hours. After transport combustor system commissioning the PCD was operated at approximately 1,400°F during five test runs. Extensive efforts were made to identify filter element failure mechanisms, evaluate material performance, and improve PCD and ash removal system operation. As a result, the reliability of the PCD system was significantly improved.

Although the transport reactor operated successfully as a combustor, the greatest potential for commercial application lies in using the transport reactor as a gasifier.

Gasification Commissioning Runs

The transport reactor was reconfigured as an air-blown gasifier in 1999 by removing the solids cooler from service and commissioning the atmospheric pressure char and syngas combustors[1]. The transport reactor has operated for over 2,300 hours in gasification mode as of May 2002. Fuels tested to date include a mixture of four PRB Coals, an Illinois #6 coal from the Pattiki mine, and an Alabama Calumet Mine bituminous coal.

The first gasification commissioning runs were hampered by poor PCD cleaning due to high solids loading and uneven gasification system operation. The highest heating values were achieved with PRB coal, since PRB coal is more reactive than the bituminous coals. The carbon content in the circulating solids was extremely low due to inefficient solids collection and recirculation.

After these runs the transport reactor was modified to improve solids collection and recirculation: a loop seal was added underneath the primary cyclone and the disengager barrel was lengthened. The modifications were very effective, allowing much higher solids circulation rates and higher coal feed rates (Figure 2). This resulted in lower relative solids loading to the PCD and higher char retention in the reactor loop, giving a higher $CO:CO_2$ ratio and higher carbon conversion (Figure 3).

The final gasification commissioning run was completed in March 2001 after 242 hours of operation. A blend of several Powder River Basin coals with Bucyrus limestone from Ohio was used. Gasifier and PCD operations were stable, but the coal feed system experienced problems with fine coal grinds. Based on the experience of this run, several modifications were made to the system. To prevent tar formation during startup, a coke breeze feed system was implemented that raises the gasifier temperature to 1,600°F before starting coal feed[2].

During gasification commissioning several challenges were encountered with the PCD: solids characteristics changed dramatically from those encountered during combustion, large pressure drops were encountered, the syngas and char caused filter materials problems, and particulate-laden syngas sometimes leaked through the filter holders. These problems were overcome by the gasifier modifications mentioned above and by adjusting the PCD operating conditions, selecting better materials, and designing improved filter holders. Monolithic SiC, composite, and metal filter elements were all used during gasification commissioning runs.

Gasification Test Campaigns

The first gasification test campaign was started in July 2001 and continued until September 2001. Gasifier and PCD operations were very stable, with the longest period of continuous

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[1] These two pieces of equipment will not be used in a commercial plant, but are used at the PSDF to dispose of the syngas and char.

[2] The startup heater at the PSDF is undersized and difficult to replace. A commercial facility will use a natural gas-fired startup burner rather than a gas-fired burner supplemented by a coke breeze feed system.

operation being more than 500 hours. Figure 4 shows gasifier temperature and pressure data from this run. Synthesis gas heating values corrected for heat losses and dilution effects[3] were between 100 and 120 Btu/SCF (Figure 5), and cold gas efficiencies, with the same corrections, were between 70 and 75 percent. Carbon conversion rates consistently over 95 percent were achieved, which is excellent for a fluidized-bed gasifier. Gasifier performance can be improved by using a finer coal grind and by other adjustments. Modifications are under way that will allow finer coal to be reliably fed. The initial gasification testes concentrated on Power River Basin (PRB), sub-bituminous coals because their high reactivity and volatile content enhances gasification.

The second test campaign was started in December 2001 and completed in April 2002. The main focus was commissioning the reactor modifications for oxygen-blown operations and performing initial operability tests with bituminous coal. Data evaluation from these tests is ongoing.

Because of the high mass transfer rates in the transport reactor, sulfur capture depends on the equilibrium characteristics of the syngas components rather than the amount of sulfur in the coal. When gasifying PRB coal less than 100 ppmv of hydrogen sulfide is expected in the syngas (equal to about 25 ppmv in the flue gas prior to final sulfur removal). The equilibrium of syngas components from bituminous coal will actually yield a lower hydrogen sulfide concentration than with PRB coal despite typically larger quantities on sulfur in bituminous coal. Additional testing with bituminous coal and the first oxygen-blown test run are scheduled later in 2002.

Iron aluminide filters were extensively tested during the gasification test campaign, with the longest exposure time (1,700 hours) being in the 700-900°F temperature range. PCD performance was within design parameters with stable baseline and peak differential pressures (Figure 6). Because of the improvements made during the gasification commissioning runs, char removal efficiencies were excellent, with outlet dust measurements consistently less than 1.0 ppmw.

Initial gasification tests have concentrated on Powder River Basin sub-bituminous coals because their high reactivity and volatiles content enhance gasification. Future gasification tests are planned with bituminous coals to verify their commercial suitability. Sulfur emissions are expected to be low with bituminous coals, despite their typically higher sulfur content. Because of the high mass transfer rates in the reactor, sulfur capture depends on equilibrium characteristics of the syngas components, rather than on the amount of sulfur in the coal. When temperature and CO_2 levels are properly controlled, PRB coal gasification produces less than 100 ppmv of sulfur in the syngas (or stack SO_2 emissions of about 25 ppmv). The equilibrium of syngas components from bituminous coal will actually yield a lower sulfur concentration than with PRB coal, despite larger quantities of sulfur in the coal.

[3] These adjustments are made to indicate what the heating value would be from a comparable commercial-sized gasifier. A commercial transport reactor will be larger and thus have relatively less heat loss, will use less instrumentation and associated nitrogen purges, and will not use nitrogen for coal conveying.

IV. COMMERCIAL DESIGN STUDY

A conceptual plant design and cost estimate have been completed for a commercial power plant based on an air-blown transport gasifier supplying fuel to a GE 7FA combined cycle. A simplified process flow diagram of the TRIG™ process is shown in Figure 7. Major design bases are as follows.

- nominal 300 MW, net output
- air-blown KBR transport gasifier
- KBR transport char combustor
- Powder River Basin sub-bituminous coal
- sorbent injected into the gasifier to control SO_2
- one GE 7FA gas turbine in a combined cycle configuration
- gasifier PCD operates at 750°F
- combustor PCD operates at 1,000°F

Plant design and performance estimates are based on data and operating experience collected operating the Transport Reactor and PCD at the PSDF in combustion and gasification modes. Gas turbine performance was provided by GE Power Systems.

System Description

TRIG™ Gasification Island

The gasification island in this initial TRIG™ design is centered around an air-blown transport gasifier, fed with nominally 3,000 tons per day of Powder River Basin sub-bituminous coal. A supplemental air compressor supplies 65 percent of the process air required by the gasifier and combustor, and the balance is extracted from the gas turbine. This arrangement has two major benefits: it allows the power output of the gas turbine to be maximized at different ambient conditions by varying the relative air flow rates, and it also greatly increases the operational flexibility of the system, which is critical during startup. The air extracted from the gas turbine compressor is cooled, boosted in pressure, and regeneratively heated before it is mixed with air from the supplemental compressor.

The gasifier converts coal, air, and steam into approximately 1,000,000 lb/hr of low-Btu syngas at 385 psia and 1,800°F. Limestone is fed to the gasifier at a coal:limestone ratio of 40:1 and captures most of the sulfur in the coal during the gasification process. After solids removal in the disengager and cyclone, the syngas is cooled to 750°F in a fire-tube heat exchanger by raising high-pressure steam. The remaining entrained char is then removed in a PCD using iron aluminide candle filters. Ninety-five percent of the carbon in the coal is converted to syngas. The remaining carbon--together with reacted sorbent, un-reacted sorbent, and ash--is cooled and fed to the transport char combustor. A small portion of the cleaned syngas is recycled through a compressor back to the process to assist solids circulation in the gasifier and to pulse clean the gasifier PCD. The remaining syngas is piped to the gas turbine. During system start-up, natural gas-fired burners heat the gasifier and char combustor before solids are introduced.

The design syngas composition, by volume percent, is as follows:

CH_4	--	2.10
CO	--	19.95
CO_2	--	7.45
H_2	--	10.33
HCN	--	0.03
H_2O	--	4.72
N_2	--	55.35
NH_3	--	0.07
Total	--	100.00

The transport char combustor consumes more than 99.9 percent of the carbon that enters. The combustor circulating bed temperature is maintained at 1,600°F by a fluidized-bed solids cooler that raises high-pressure steam.

The flue gas leaving the combustor is cooled to 1,000°F by raising high-pressure steam and the entrained ash is removed in the combustor PCD by iron aluminide candle filters. The clean flue gas passes through a hot gas expander that generates 5.2 MW of power, and then goes to the stack at 350°F. The ash is cooled, depressurized, and transported to storage silos, from which it is removed by truck to a 5-year, dry storage landfill.

Combined Cycle Island

A GE 7FA gas turbine, modified for operation on syngas, is at the heart of the combined cycle power island. The modifications include replacing the standard dry low-NO_X combustor cans with flame diffusion combustors (to prevent flashback) and replacing the first stage of the expander to accommodate increased mass flow associated with the dilute syngas fuel. The gas turbine is flat-rated on syngas at the shaft power limit (197 MW) by varying the amount of extraction air that is withdrawn when ambient conditions change.

The gas turbine uses natural gas when syngas is not available, both during gasifier outages and gasifier start-up. If natural gas is not available at a site, fuel oil could be used instead of natural gas. When the gas turbine is firing natural gas, water is injected into the combustion cans to limit thermal NO_X formation. An evaporative cooling system at the gas turbine compressor inlet is used when the ambient temperature is above 65°F.

The heat recovery steam generator (HRSG) is a single pressure unit with reheat. During syngas operation, most of the high-pressure water from the economizer is routed to the gasifier island steam drum. The water moves by natural circulation between the steam drum and three steam-generating coolers. Saturated steam is returned to the HRSG where it is mixed with steam from the HRSG steam drum, and then fed to the superheat sections. The final steam conditions are 1,820 psia/1,000°F/1,000°F. The HRSG exhaust temperature is 290°F, which is well above the acid dewpoint of the flue gas. A selective catalytic reduction (SCR) system is included in the HRSG to reduce NO_X emissions. Ammonia slip is controlled in the SCR to minimize ammonium bisulfate production.

The HRSG is integrated with the gasification island in three additional ways. First, a small process steam flow for the gasifier is extracted from the cold reheat line. Second, the condenser discharge is routed through the gasifier island and is used for low level solids and gas cooling and compressor intercooling. Third, the HRSG provides high-pressure steam (at 950°F) to drive the supplemental air compressor. Steam from the supplemental air compressor steam drive exhaust is combined with steam from the main steam turbine exhaust and condensed (at 1 psia) by water from the mechanical draft cooling tower.

When the gasification island is not operating and producing high pressure steam, the HRSG alone must raise all of the high pressure steam. In this mode of operation, a duct burner upstream of the HRSG evaporator section fires natural gas to boost steam flow and pressure. The HRSG also has a natural gas-fired duct burner upstream of the last superheat section for peaking operation.

Coal and Sorbent Feed Systems

Coal is delivered to the site by unit trains of rapid discharge cars. Conveyors move the coal from the unloading area to a 15-day live coal pile at a rate of 4,000 tph. There is a 30-day dead coal storage area adjacent to the live pile.

Coal is reclaimed from the live coal pile by in-ground, vibrating reclaim bins and directed onto the reclaim conveyor, which transports it to the coal crusher. A crushed coal conveyor then takes the coal to five parallel coal drying and milling systems, each rated at 30 percent of the design feed rate. The design coal feed rate is 247,000 lb/hr. Natural gas-fired burners supply the heat needed to dry the coal.[4] Five gasifier coal feed systems, each rated at 30% of the design feed rate, pressurize the pulverized coal and feed it into the gasifier. The coal is conveyed by nitrogen, which is supplied by a leased nitrogen generation plant.[5]

The Powder River Basin coal composition (by weight percent) and heat content as fed to the gasifier are as follows:

C	-- 58.2		
H	-- 3.8		
O	-- 13.3		
N	-- 0.8		
S	-- 0.3		
Ash	-- 5.8	Higher Heating Value (HHV)	-- 9,852 Btu/lb
H_2O	-- 17.8	Lower Heating Value (LHV)	-- 9,305 Btu/lb
Total	-- 100.0		

[4] It has since been determined that it is less expensive to dry the coal with heat from condensing low pressure steam. Future TRIG™ designs will incorporate this change.
[5] Future TRIG™ designs will use recycled syngas to convey the coal, avoiding high nitrogen plant lease cost.

Crushed limestone is delivered by trucks, which unload directly to a 15-day live sorbent pile. An adjacent pile is sized for 30 days of dead storage. Sorbent reclaim, milling, and feeding are similar to the coal systems, except that the sorbent mills and gasifier feed systems are spared at 2 x 150%. Air is used to convey the limestone to the gasifier.

Plant Performance

Projected performance data for the TRIG™ plant operating on syngas and on natural gas at ambient conditions of 65°F and 60 percent relative humidity (RH) are shown in Table 1.

Table 1. Serial No. 1 TRIG™ Plant Performance at 65°F and 60% RH

	Syngas	Nat. gas	
Power Output			
Gas Turbine, Gross	197.0	162.0	MW
Steam Turbine, Gross	120.8	127.6	MW
Char Combustor Gas Expander, Gross	5.2	0	MW
Auxiliary Load	24.6	8.7	MW
Net Plant Output	298.4	280.9	MW
HHV Heat Rate and Efficiency			
Heat Input From Coal	2,435	0	MMBtu/hr
Heat Input From Natural Gas	39	2,231	MMBtu/hr
Net Heat Rate, High Side of GSU	8,290	7,940	Btu/kW-hr
Net Efficiency	41.2	43.0	%
LHV Heat Rate and Efficiency			
Heat Input From Coal	2,300	0	MMBtu/hr
Heat Input From Natural Gas	35	2,011	MMBtu/hr
Net Heat Rate, High Side of GSU	7,830	7,160	Btu/kW-hr
Net Efficiency	43.6	47.7	%

Even for this Serial No. 1 plant the heat rate on syngas, 7,830 Btu/kW-hr, LHV (43.6% efficiency), is better than that of currently available coal-based power plant technologies. Because the gas turbine is modified to use syngas, the LHV heat rate when fired on natural gas, 7,160 Btu/kW-hr (47.7% efficiency), is higher than that of currently available natural gas-fired combined cycles. However, this mode of operation increases the TRIG™ system availability, which is especially important during peak load times.

Economic Evaluation

Capital Costs

Capital costs of the TRIG™ system were estimated based on a typical greenfield site in the southeast United States. All capital costs are given in January 2001 dollars. Cost estimates were developed using commercial power plant costing software, process plant costing software, vendor quotes, and historical Southern Company cost information.

The capital cost includes estimates for equipment, labor, materials, indirect construction costs, engineering, contingencies, and land. Land is valued at $3,200 per acre. Sales tax is 5 percent and freight is 2 percent of the equipment cost. An overall contingency factor of 10 percent is applied to the estimate.

The capital costs are assembled into the categories of a Southern Company standardized work breakdown structure:

- Indirects -- engineering and environmental services, project and construction management, contractor management (contractor indirects), temporary facilities and services, production costs, builder's risk insurance, ad valorem taxes, and land
- General Site -- site preparation, site infrastructure, and non-process buildings
- Steam Generation -- HRSG (with SCR) and char combustor and associated systems
- Turbine and Generator -- gas turbine, steam turbine, condensate system, and feedwater system
- Fuel Facilities -- coal unloading and reclaim, coal and sorbent preparation and feed, gasifier process equipment, gasifier island steel structure, natural gas delivery, and fuel handling fire protection
- Emission Facilities -- syngas and combustor PCDs, sorbent reclaim, exhaust gas stacks, and ash handling and storage
- Plant Water Systems -- cooling water supply, cooling tower, condenser, service water system, water treatment and condensate makeup, and wastewater treatment
- Electrical Distribution and Switchyard -- bulk cabling and wiring, A.C. systems, emergency generator system, generator bus system, and switchyard
- Plant Instrumentation and Controls -- local racks and panels, monitoring and control systems, control consoles, and water analysis systems
- Other -- sales tax and freight, contingency, and other miscellaneous costs

The capital costs resulting from this evaluation are summarized in Table 2. The total plant cost[6] for this Serial No. 1 TRIG™ system is estimated to be $384.8 million ($1,290/kW). The costs are broken out by major functional areas in Figure 8.

[6] This includes all expenses except the cost of capital during construction and startup costs.

Table 2. Serial No. 1 TRIG™ Total Plant Cost Summary in January 2001 Dollars

Account	Cost in $million	$/kW
Indirects	78.2	262
Site, General	16.9	57
Steam Generation Area	29.9	100
Turbine & Generator Area	60.3	202
Fuel Facilities	83.2	279
Emission Facilities	24.8	83
Plant Water Systems	12.8	43
Electrical Distribution & Switchyard	14.9	50
Plant Instrumentation & Controls	15.2	51
Other	48.6	163
Grand Total	384.8	1,290

A 1 x 1 combined cycle configuration was chosen in this design to limit the total installed cost and financial risk for a first commercial facility. A second TRIG™ plant would be a 2 x 1 configuration (two gas turbines and one steam turbine) producing nominally 600 MW, and would have a lower cost per kilowatt because of economies of scale. Adjusting the 1 x 1 TRIG™ cost for this and for other "first-of-a-kind" costs gives a total plant cost estimate of $1,040/kW for a second TRIG™ plant.

A major incentive for commercializing this technology is the potential to build future (n^{th}) plants around H class gas turbines. Their high output and efficiency can enable the construction of clean, relatively simple coal-fired power plants with efficiencies over 50 percent (LHV) and total plant costs near $1,000/kW[7] for a 1 x 1 configuration. Projected cost and performance for a first, second, and n^{th} TRIG™ plant are given in Figure 9.

Comparison with Other Coal-Use Technologies

The projected performance and costs for a Serial No. 2 TRIG™ plant were compared with those of other coal-based power plant technologies given in EPRI's 2001 Technical Assessment Guide (TAG™). The following technologies were selected:

- Shell heat recovery integrated gasification combined cycle (IGCC), 2 x 1 GE 7FA
- E-GAS™ (formerly Destec) heat recovery IGCC, 2 x 1 GE 7FA
- Texaco quench IGCC, 2 x 1 GE 7FA
- supercritical (3,500 psia/1,050°F/1,050°F) pulverized coal (PC) plant with FGD

[7] *Market-Based Advanced Coal Power Systems, Final Report*, Office of Fossil Energy, U.S. Department of Energy, Washington, DC, November 1999.

Because the plant sizes are different and have different economies of scale, all of the costs were normalized to 500 MW using the TAG™ procedure. The following economic parameters were used to calculate the cost of electricity for these technologies:

- fuel cost[8] = $1.25/MMBtu
- fuel cost yearly escalation = -1.03%
- book life = 20 years
- capacity factor = 80%
- carrying charge factor = 0.142

The results are summarized in January 2001 dollars in Table 3 and Figure 10. The costing procedures used to develop the EPRI TAG™ power plant costs are similar to those used in the TRIG™ study, but data are only available for Illinois #6 bituminous coal rather sub-bituminous coal as used for the TRIG™ estimate. Cost and performance of the TRIG™ plant on bituminous coal are not currently known, but the differences are not expected to be large. Nevertheless, the comparisons should be used with caution.

The total plant cost of a Serial No. 2 TRIG™ plant is projected to be lower than for three of the other coal-based power plant technologies, and approximately the same as the fourth (supercritical pulverized coal plant). The Serial No. 2 TRIG™ heat rate and maintenance costs are projected to be better than for the other plants. The cost of electricity for the Serial No. 2 TRIG™ (3.70 cents/kW-hr) is projected to be the lowest of the group.

Table 3. Comparison of Coal-Based Power Plant Technologies, in 2001$

	Ser. No. 2 TRIG™	Shell	E-GAS	Texaco Quench	PC
Plant Performance					
Normalized Plant Size, MW	500	500	500	500	500
Heat Rate, Btu/kWh, LHV	7,420	7,930	7,950	9,020	8,630
Efficiency, LHV	46.0	43.1	43.0	37.9	39.6
Plant Costs					
Total Plant Cost*, $/kW	1,080	1,350	1,170	1,160	1,070
Fixed O&M, $/kW-yr	30.3	39.4	35.0	36.5	27.5
Variable O&M, $/MW-hr	1.8	2.2	2.2	2.2	2.8
Levelized Costs					
Capital, cents/kW-hr	2.19	2.74	2.37	2.35	2.17
O&M, cents/kW-hr	0.61	0.78	0.72	0.74	0.67
Fuel, cents/kW-hr	0.90	0.94	0.94	1.07	1.02
COE, cents/kW-hr	3.70	4.46	4.03	4.16	3.86

*Adjusted using the formula $TPC_1 = TPC_2 (MW_2/MW_1)^{0.245}$

[8] Fuel cost is the average for the United States and is taken from *Annual Energy Outlook 2001*, Energy Information Administration, Washington, DC, December 2000.

V. PROJECTED ENVIRONMENTAL PERFORMANCE

Estimated emissions are given (in three different units of measure) in Table 4. Mercury emissions were not estimated due to insufficient data. However, a Southern Company proprietary technology to control mercury is being developed.

Table 4. Current Estimated Serial No. 1 TRIG™ Emissions

	lb/MMBtu	ppmv	lb/MW-hr
NO_x	0.04	10	0.30
SO_2	0.02	4	0.15
CO_2	217	--	1,770
particulates	0.004	2.0*	0.03

* particulate concentration is reported in ppmw

VI. FUTURE RESEARCH PLANS

NETL, Southern Company, and other participants are currently planning the next five years of research at the PSDF. The main goals are to support DOE's Vision 21 program for developing the next generation of power plants and to support commercialization of an air-blown transport gasifier-based power system. Major proposed activities for 2002 through 2006 include the following:

- continue air-blown and oxygen-blown gasification development
- integrate oxygen-blown gasifier with advanced air separation technology
- integrate gasifier with existing combustion turbine at the PSDF
- evaluate multi-contaminate (H_2S, Hg, HCl, etc.) controls
- evaluate novel CO_2 and H_2 separation systems
- test advanced materials in gasifier and CT test section
- evaluate high temperature gas and particle sensors
- improve system integration and controls
- improve gas cooling technology
- improve coal and limestone feed systems and ash cooling systems

VII. CONCLUSIONS

A coal-fired transport gasifier-based power plant that includes a high temperature, high pressure PCD holds promise for near-term commercialization, based on test results at the PSDF. Approximately 5,000 hours of combustion and over 2,300 hours of gasification tests have been completed with excellent performance.

A commercial design study of the Transport Reactor Integrated Gasification Combined Cycle (TRIGCC™) shows that a first plant will encounter typical Serial No. 1 problems of high capital and operating costs. However, subsequent plants are expected to be competitive with other coal-based power systems even before the full potential of a plant based on H class gas turbine technology is realized.

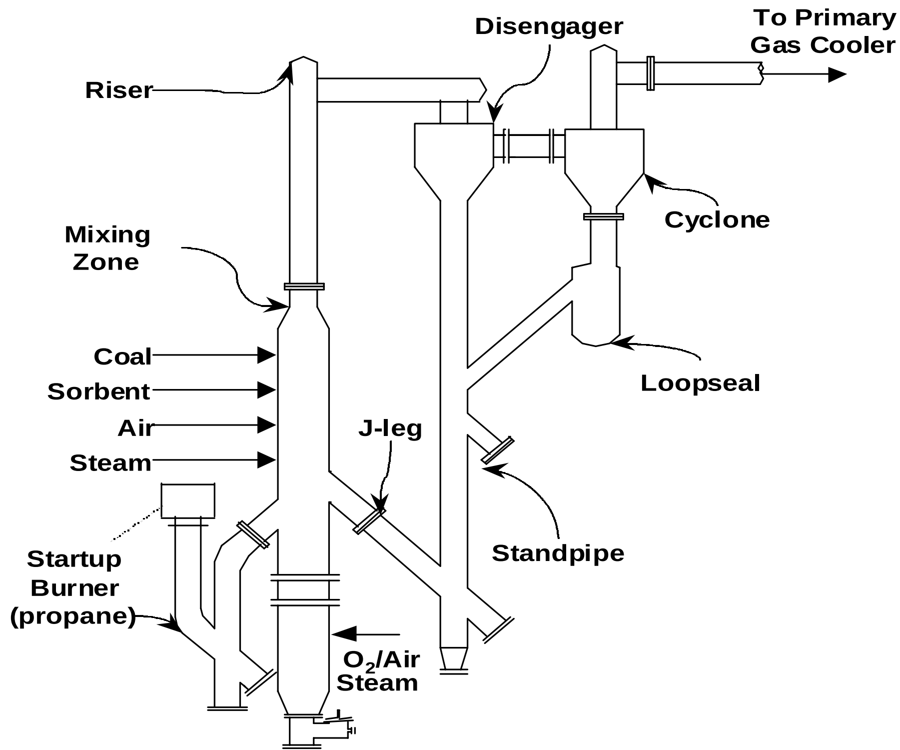

Figure 1. Transport Gasifier

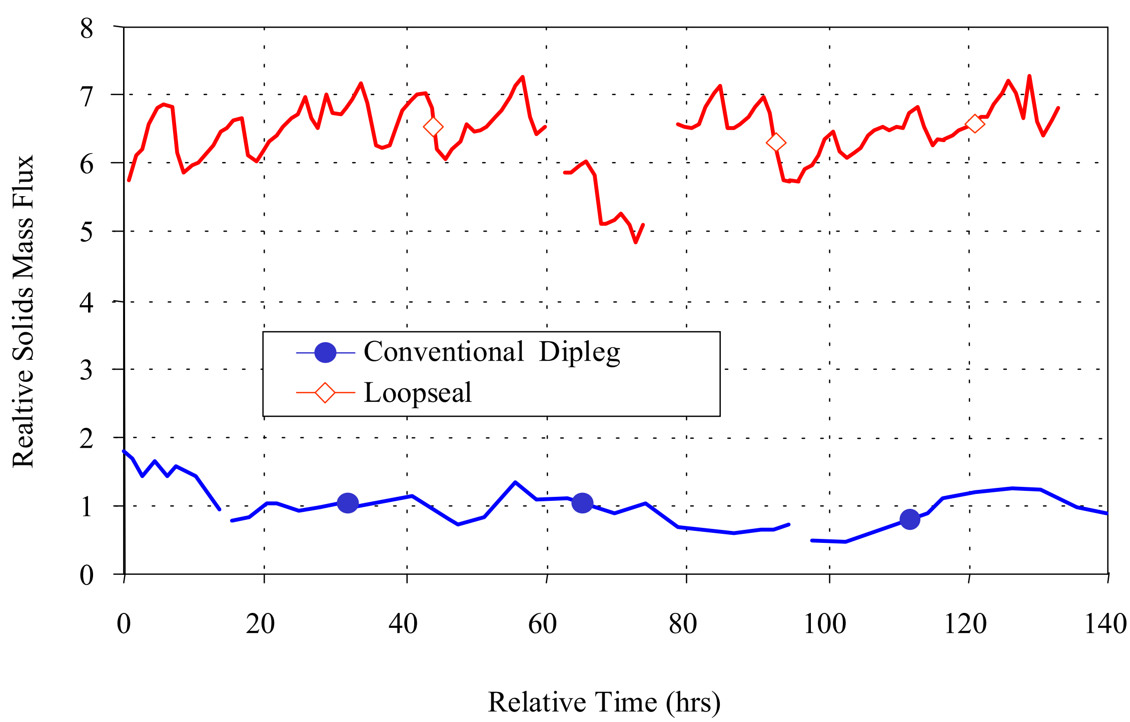

Figure 2. Relative Solids Mass Flux in Gasifier Before and After Loop Seal Addition

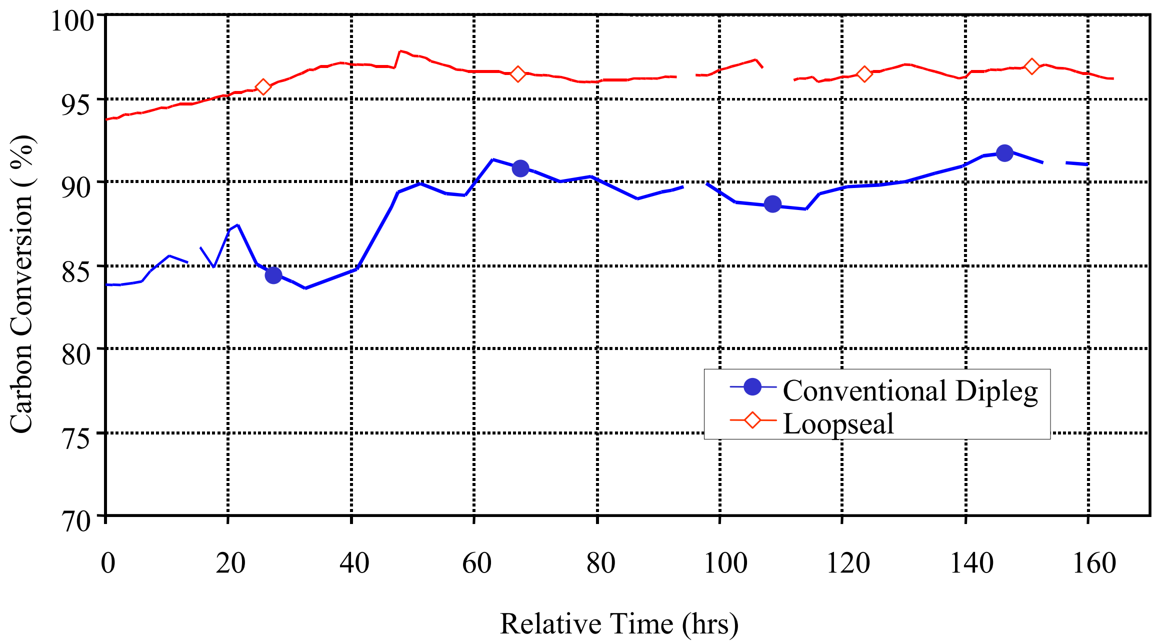

Figure 3. Carbon Conversion Before and After Loop Seal Addition

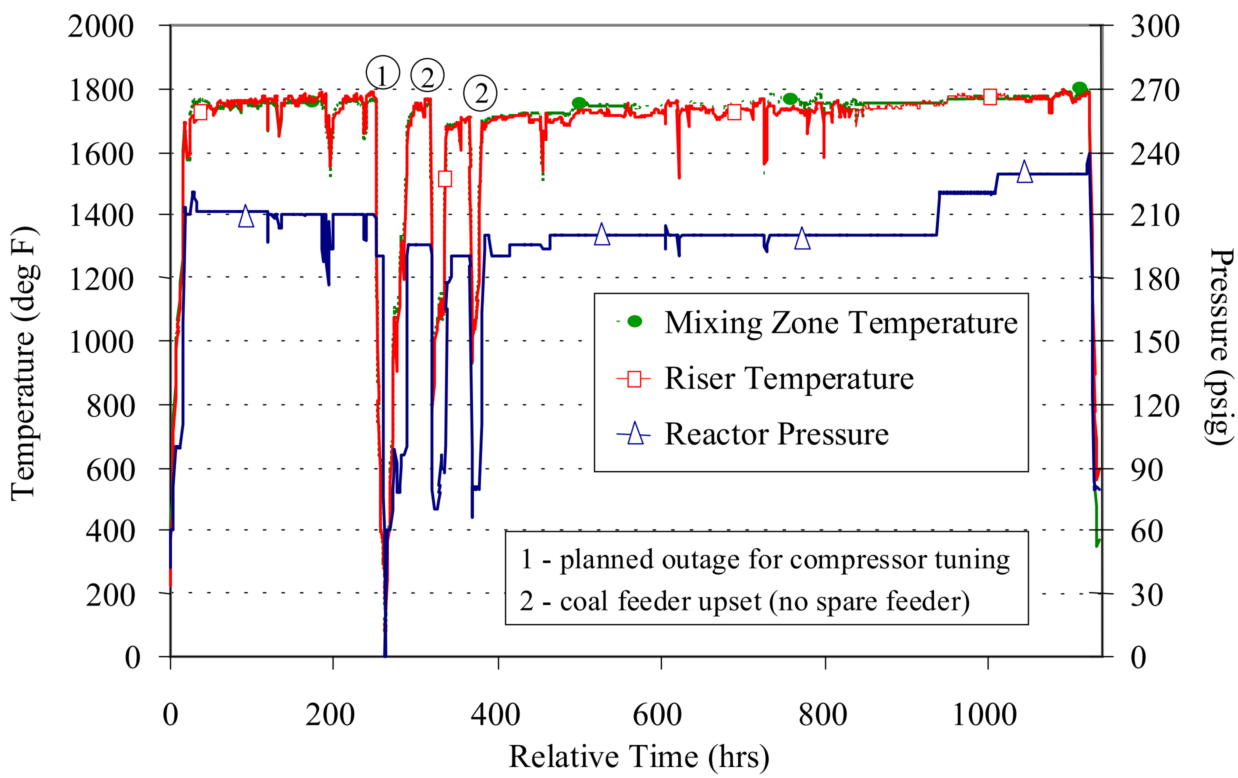

Figure 4. Gasification Test Campaign Temperature and Pressure Data

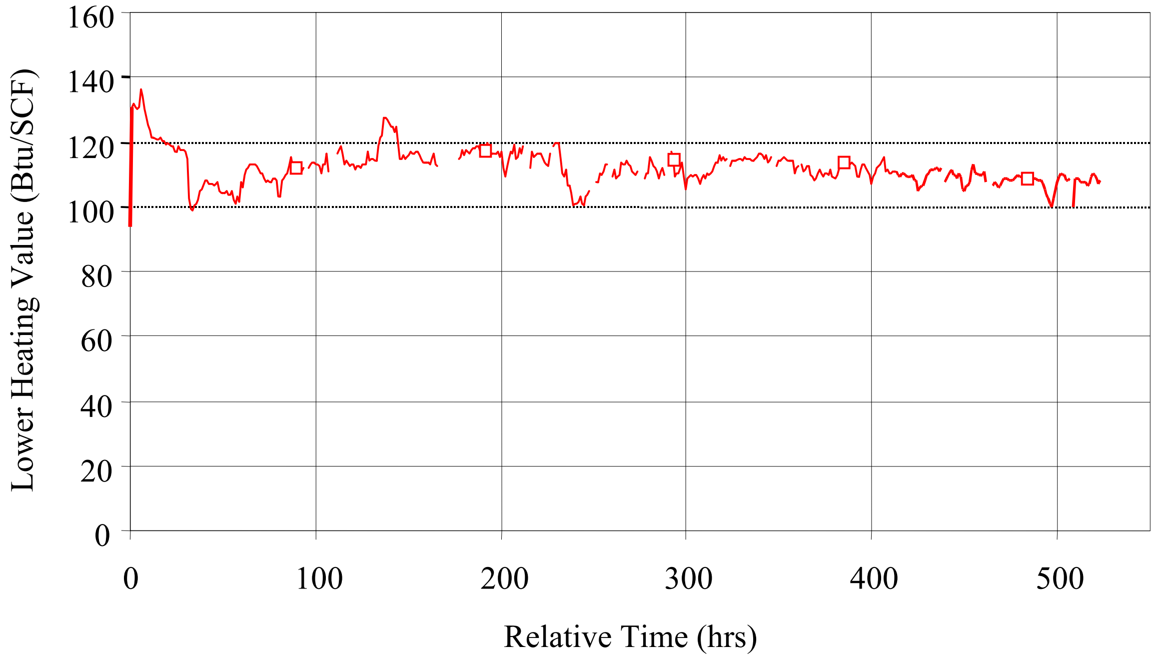

Figure 5. Gasification Test Campaign Syngas Heating Value

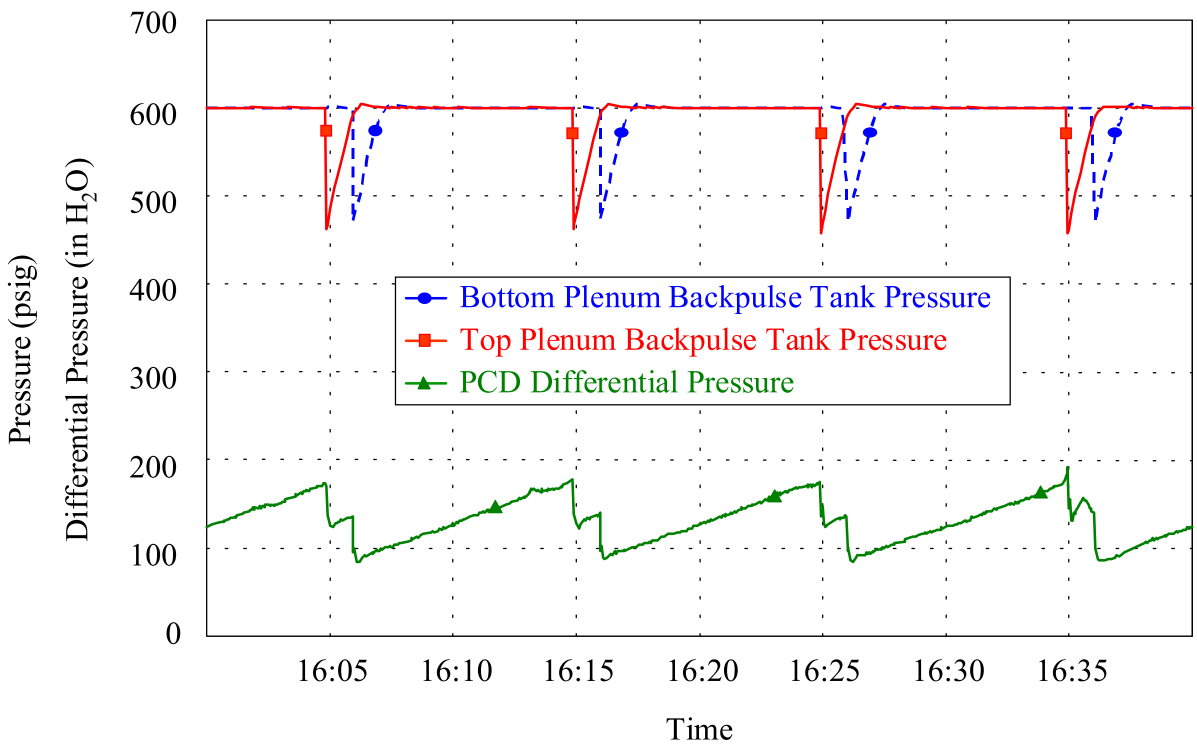

Figure 6. Typical PCD Backpulse Tank Pressures and PCD Differential Pressure

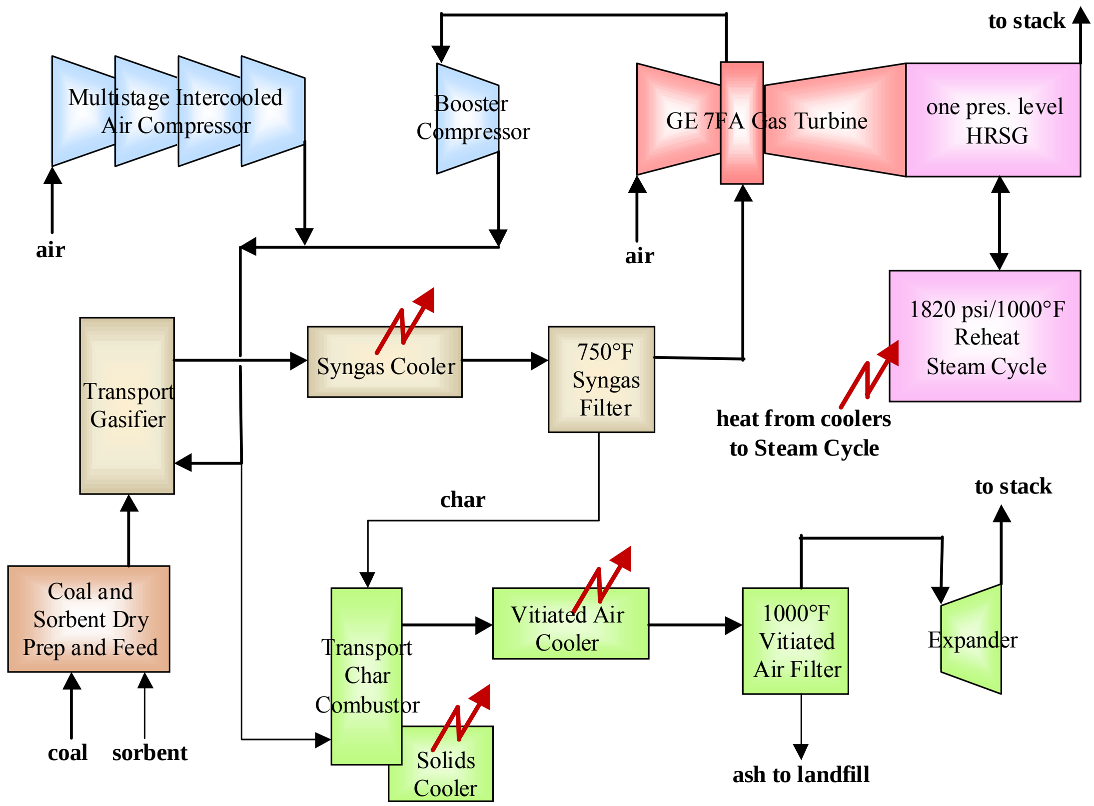

Figure 7. Simplified TRIG™ Process Flow Diagram

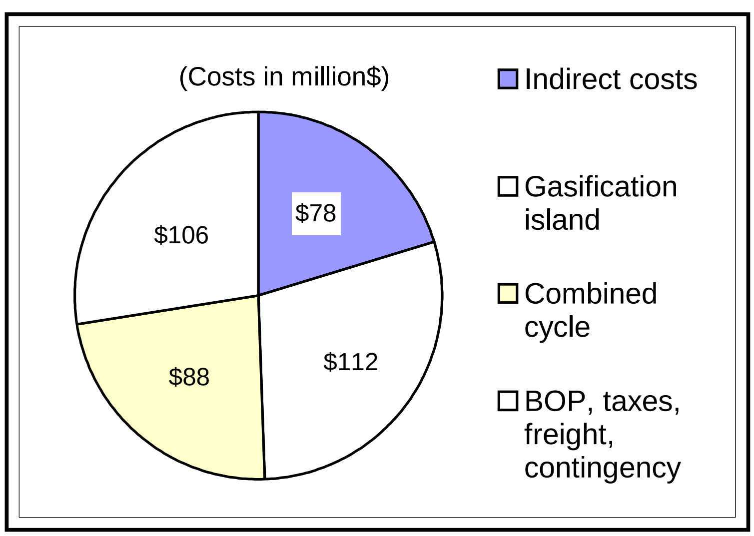

Figure 8. Serial No. 1 TRIG™ Capital Costs Broken Out by Major Functional Area

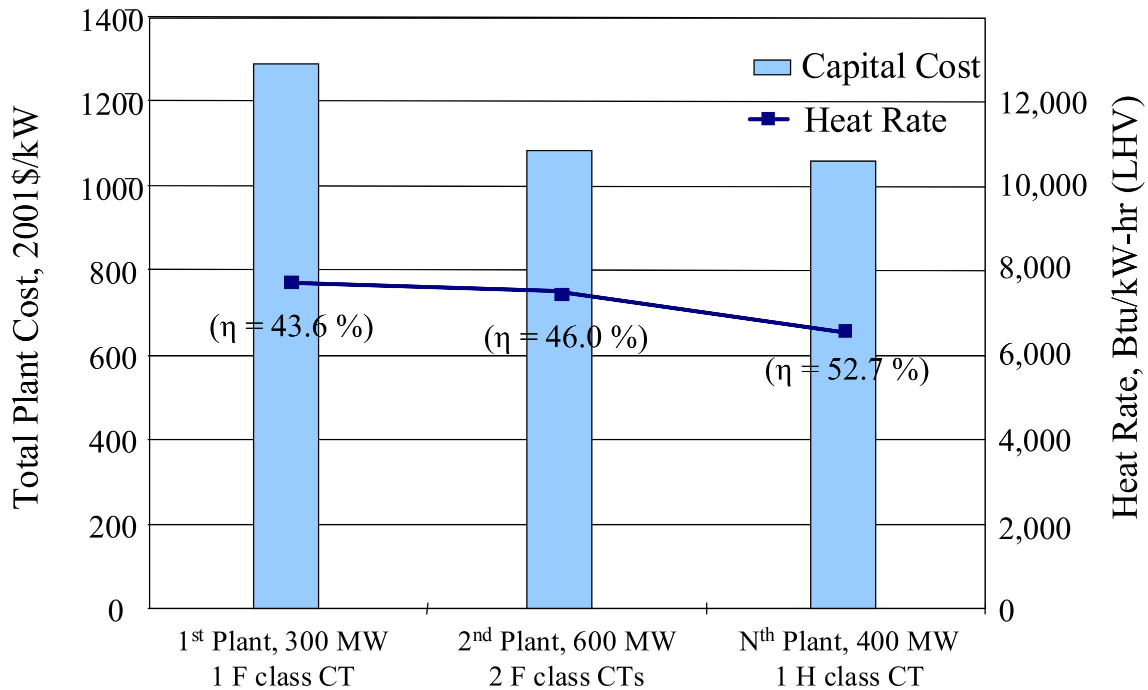

Figure 9. Projected TRIG™ Cost and Performance Improvements With Subsequent Plants

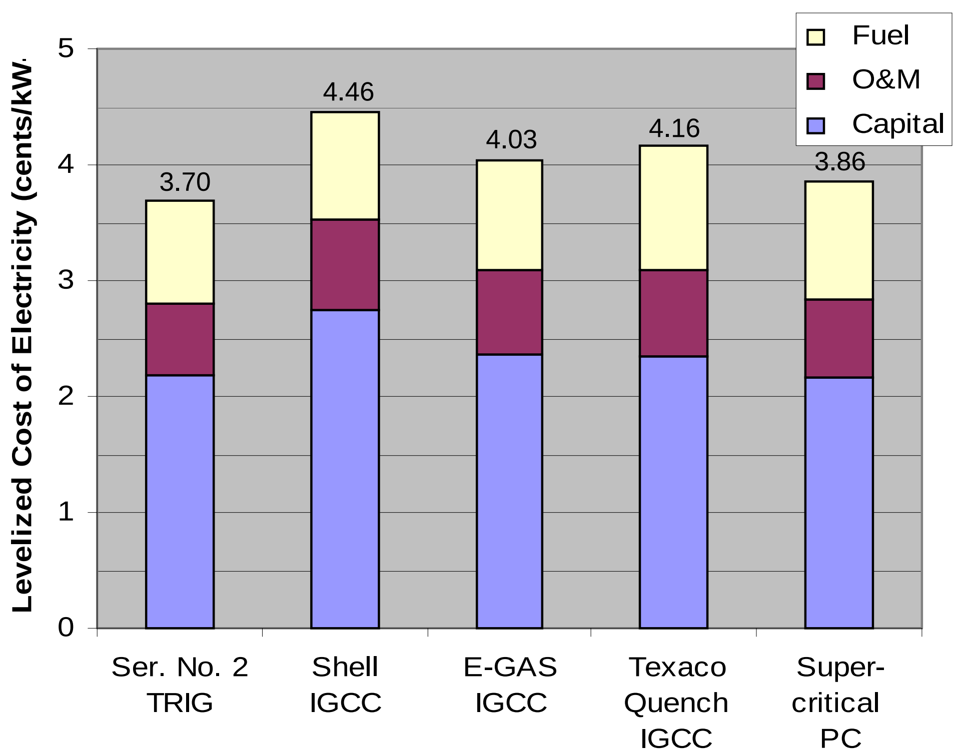

Figure 10. COE Comparison with Coal-Use Technologies from EPRI TAG™